Demand flexibility versus physical network expansions in distribution grids

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HIGHLIGHTS

- Demand flexibility can be used to defer physical network expansions.
- Through the proposed model, FlexMart, consumers can offer their flexibility for a fixed, riskless benefit.
- Through FlexMart, the DSO can reduce its total costs by using the available flexibility to relieve the network from congestion events.
- Regulation on energy markets and pricing can be a catalyzer for flexibility to become a success story.

ABSTRACT

The volumes of intermittent renewable energy sources (RES) and electric vehicles (EVs) are increasing in grids across Europe. Undoubtedly, the distribution networks cope with congestion issues much more often due to distributed generation and increased network use. Such issues are often handled by unit re-dispatching in short term and grid expansion in long term. Re-dispatching is, however, not always an appropriate solution for local distribution networks since the limited generation units are mostly RES of uncontrollable volatility. Recovering the incurred investment costs on the other hand would trigger an increase of the network tariffs. A possible solution is todefer such an investment by utilizing the demand side resources. The FlexMart model, developed and suggested in this paper, provides the ability for the Distribution System Operator (DSO) to purchase demand flexibility offered by residential consumers. Two feeders with different topologies are tested and the ability of the suggested mechanism to provide benefits for the involved stakeholders, both the DSO and the consumers, is demonstrated. The developed empirical model, works as a long-term planning tool and has the ability to provide an optimal combination of physical expansions and flexibility dispatch to reassure the stable and secure operation of the grid.

Keywords: Flexibility, renewables, intermittency, DSO, network investment

Nomenclature

n	Node
t	Time
l	Line
TC	Total Cost [€]

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c_{exp}	Expansions costs [€]
c_{curt}	Curtailment costs [€]
C_{flex}	Flexibility costs [€]
C_{line}	Expansion cost per unit [€/kW]
k_{exp_l}	Volume of expansion [kW]
P_t	Price [€/kWh]
Q_t^{Dn}	Power demand [kW]
$q_t^{D_n}$	Optimal demand after flexibility dispatch [kW]
$q_t^{D_{down_n}}$	Volume of down-regulated demand [kW]
$q_t^{D_{up_n}}$	Volume of up-regulated demand [kW]
INV_{flex_n}	Investment cost for flexibility [€]
ROI	Return on investment rate [.00]
$curt_{n,t}$	Volume of curtailed power [kW]
p_{imp_t}	Volume of power imported through the feeder [kW]
$PV_{n,t}$	Output power of PV [kW]
$f_{l,t}$	Power flow [kW]
CAP_l	Line capacity [kW]
BP	Base Power [kVA]
θ_{n_i}	Power angle [º]
Z_l	Line impedance [Ω]
$COEF_{flex}$	Flexibility coefficient [.00]

Abbreviations

RES	Renewable Energy Sources
DSO	Distribution System Operator
EV	Electric Vehicle
ROI	Return on Investment
GHG	Green House Gases
SO	System Operator
CAPEX	Capital Expenditure
OPEX	Operational Expenditure
LV/MV/HV	Low/Medium/High Voltage
NPV	Net Present Value
MP	Market Power
TSO	Transmission System Operator
IB	Incentive-Based
PB	Price-Based
DR	Demand Response
LINEAR	Local Intelligent Networks and Energy Active Regions
FLECH	FLExibility Clearing House
BRP	Balancing Responsible Party
GRASP	Greedy Randomized Adaptive Search Procedure
CHA	Constructive Heuristic Algorithm
MILP	Mixed Integer Linear Programming
AU	Aggregating Unit
PV	PhotoVoltaic
KPI	Key Performance Indicator

1. Introduction

Flexibility can be defined as the ability of a power system to utilize its resources to respond to changes in net load (Lannoye, 2012). Demand side flexibility refers to the part of the load which is shiftable without violating comfort standards of the consumers (Tahersima, Madsen, & Andersen, 2013). Flexibility can be part of efficient strategies, such as to facilitate the integration of intermittent RES to the grids (Heussen, Koch, Ulbig, & Andersson, 2012). Moreover, the need to integrate more RES to the grids is continuously increasing, in an attempt to transition to a sustainable, cleaner power system. From a European point of view, the commonly adopted 20-20-20 goals described on the "3rd package" (European Commission, 2009), foresee a turn towards renewable resources in order to minimize CO_2 and emissions of greenhouse gasses (GHG). The intermittent nature of these resources causes several issues, not only from a technical perspective but from an economic one likewise.

For the sake of consumers' comfort, the grids must have adequate capacity to provide the connected users with high-quality uninterrupted power under any circumstances. However, the uncontrollability of the output level of RES increases the occurrences of congestion problems in the distribution grids. Investing in grid facilities, i.e. power lines, feeders and substations, is capital intensive. Moreover, considering the fact that these additional investments are utilized when load is peaked and hence only for some hours per year, the question which arises is if such an approach is actually efficient. The implementation of such a solution however becomes more difficult due to the increasing share of intermittent RES integrating to the grids. Another option would be to use a market-oriented approach instead of physical expansions or re-dispatching. Traditionally, flexibility has been provided by the generation side through a re-dispatching of units and starting-up auxiliary units. . Existing technologies allow a "smart" communication between the different actors of the power system. Hence, a solution which utilizes the available demand side flexibility could possibly provide an alternative to physical expansions (Dansk Energi, 2012).

This paper assesses the possibility of mobilizing residential demand side resources in order to defer physical expansions in local distribution networks. In order to empower consumers to offer their demand resources to the grid, specifically here to the DSO, the designation of an appropriate incentivizing mechanism is proposed. The incentives for the consumers come from either savings from price differences, i.e. shifting consumption from peak hours with high prices to lower priced hours; or by providing an adjusted fixed benefit. In this paper, flexibility is dispatched according to the needs of the DSO in order to minimize its required investments, while the flexibility remuneration mechanism is a combination of both approaches in order to limit the risks for consumers. The choice for such a regulated approach is motivated. A small local market can have a lot of capabilities and potential, however, it is assumed that it has limited liquidity. Consequently, market power can easily be concentrated and potentially exploited, exposing the market participants to risk. More details on the proposed mechanism are provided in section 3.

The main contribution of this paper is the provision of a mechanism that valorizes fairly the demand flexibility resources, considering DSOs and consumers best interests alike. The methodology used consists of two directions. First, the development of a conceptual market model and second, the development of an empirical planning model using mixed integer linear programming (MILP) on the GAMS software system. The selection of this two-fold methodology, conceptual and empirical, is justified by the intention of the authors to conduct both qualitative and quantitative research on the topic. Following this introductory section, section 2 contains the literature review in the context of flexibility markets and recent projects. The proposed pricing structure and modeling are analyzed in section 3. Section 4 hosts the results obtained from the empirical model and a brief discussion on them, whilst section 5 serves a conclusive purpose.

2. Literature review

Following the recent evolutions, distribution networks face various challenges. The continuously increasing penetration of the intermittent RES, the rising EV market and the fact that distribution grids were not designed to accommodate distributed generation add a lot of stress to the grid (Perez-Arriaga & Battle, 2012), (Cossent, Gomez, & Frias, 2009), (Van der Welle & de Joode, 2011). Despite its various benefits, distributed generation, RES and EVs might result in congestion issues (Pepermans, Driesen, Haeseldonckx, Belmans, & D'haeseleer, 2005), (Clement-Nyns, Haesen, & Driesen, 2010), (Schmutzler & Wietfeld, 2010) as well as policy implications (Joorde, Jansen, Welle, & Scheepers, 2009). Such issues hinder the stability of the system due to over-loading of the lines and may lead to involuntary load shedding, having hence a negative impact towards the security and reliability of the system (Papalexopoulos, 1997), (Hogan, 1997). Common approaches to relieve transmission networks include, among others, re-dispatching of generators and making use of control devices (Nordel, 2000), (Christie, Wollenberg, & Wangstien, 2000). Units re-dispatching is not applicable to a distribution grid since its generating units are primarily RES, whose output level is not controllable. Hence, one of the problems that grid operators face is the need for incremental reinforcement of the grid (Joorde, Jansen, Welle, & Scheepers, 2009).

An approach to the distribution network investment planning would be to incorporate the DSO ratemaking regulation to the investment problem through utilization factors for the different network components, e.g. substations, lines, etc. (Giacomini, Santos, Neto, & Abaide, 2013). Another methodology based on the PECO model (Román, Gómez, Muñoz, & Peco, 1999), proposes the use of the GIS data in order to expand the distribution grid alongside the road system and hence avoid infeasibilities and barriers (Domingo, Roman, Sanchez-Miralles, Gonzalez, & Martinez, 2011). The optimal siting and sizing of DERs in order to limit grid expansions is investigated in (El-Khattam, Hegazy, & A.Salama, 2005). In the same study it is shown that proper planning can reduce the expansion costs by about 20%.

It is, however, argued that DSOs might need to seek for innovative solutions beyond grid reinforcements and that flexibility is a rather important feature of the power system. (Perez-Arriaga & Battle, 2012), (Bayod-Rujula, 2009), (Mendez, Rivier, Fuente, Arceluz, & Marin, 2006), (Cochran, et al., 2014), (Katz, 2014), (Ruester, Schwenen, Batlle, & Perez-Arriaga, 2014). The increasing penetration of intermittent RES decreases the supply side flexibility (Bosman, 2015), (Droste-Franke, et al., 2012). That creates a “flexibility gap”, which in turn should be covered to reassure reliability and security of the power system (Papaefthymiou, Grave, & Dragoon, 2014). From the demand side, flexibility can be provided by industrial and residential or commercial consumers. Industrial demand response is a mature technology. In several markets, industrial consumers provide already their demand resources through balancing markets and a lot of research has assessed its impacts and benefits (Bjork, 1989), (Flory, Peters, Vogt, Keating, & Hopkins, 1994), (Rahman & Rinaldy, 1993), (Roos, 1996). In the residential and commercial applications such as heating and cooling, there are possibilities to enable demand response. Additionally, rescheduling of washing activities in households might enhance those possibilities. Household demand response has a very high potential, however, it is still, not a mature technology (Papaefthymiou, Grave, & Dragoon, 2014).

It is needed to ensure that sufficient incentives are provided so that active load management on the demand side is a possibility (Cochran, et al., 2014), (Katz, 2014). Operations concerning flexibility provision, such as a demand down-regulation, should be explicitly rewarded through a designated market mechanism (Schmalensee, 2011). It is anticipated that flexibility contracting through a local market might be effective in deferring grid augmentations (Ramos, De Jonghe, Gomez, & Belmans, 2014). The necessity of a fair market that enables consumer participation, is open to the demand-side resources and enables well-managed payments and risks is evident (Actility, Anode, EnergyPool, & REstore, 2014). Aggregators can integrate the capabilities of small consumers and hence, allow them to participate in such a flexibility market (EURELECTRIC, 2014). Concerning the remuneration of the flexibility services a distinction is made between the incentive-based (IB) and the price-based (PB) schemes

(Ramos, Jonghe, Six, & Belmans, 2013). In the former, the participants of such schemes are receiving a fixed benefit and their load is directly managed by operators when necessary. In the latter, consumers can participate through a pricing scheme and their benefit derives from consuming when the price is lower.

Summing up, it is identified that demand flexibility may defer incremental distribution grid expansions, however, this area has not yet been studied in detail. This paper, goes beyond the investigation of demand flexibility's effects. The model developed in this paper, namely FlexMart, proposes a market mechanism and a remuneration scheme, that will be presented in the next section.

3. Methodology

In order to tackle the objective of this paper, both a conceptual and an empirical model are developed. Through these models, the potential of the DSO to contract flexibility for deferring investments in grid assets is assessed. Following the literature review, the methods employed to solve the research question comprise of two directions. Firstly, the development of a conceptual market model and secondly, the development of an empirical planning model using mixed integer linear programing (MILP) on the GAMS software system. An overview of the methodology employed, from literature review to the interpretation of the empirical results, is illustrated in **Fig. 1**.

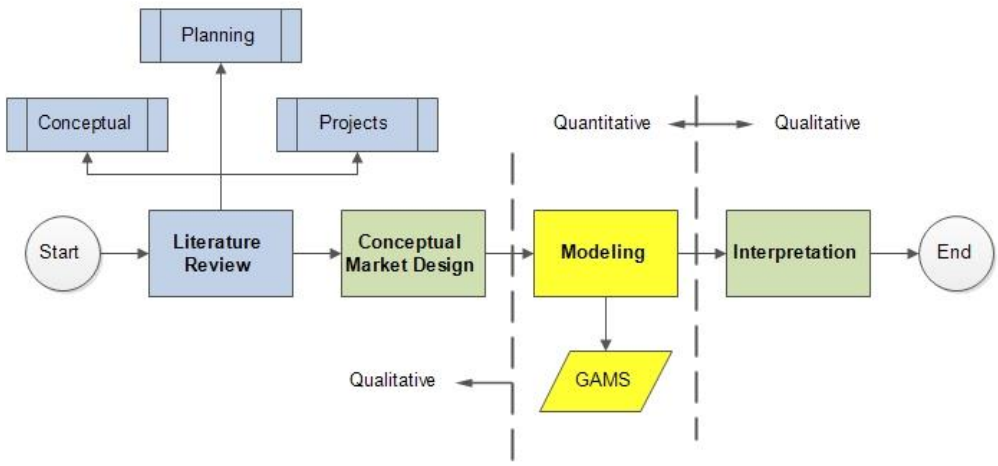


Fig. 1. The methodology at a glance.

3.1. Conceptual Model

A risk-free scheme that induces the minimum possible costs is desired and is proposed by FlexMart, a model developed for the purposes of this work. The aim is to create a 'win-win' situation for the involved stakeholders, namely, the DSO and the consumers.

In **Fig. 2**, the cost for accommodating a residual quantity of power, Q_d (MW), with investing in grid assets, C_i (€), and with purchasing flexibility, C_f (€), are compared. The difference between investment and flexibility costs, creates a margin, $C_i(Q_d)$-$C_f(Q_d)$, that depicts the gross incurred savings for the DSO when physical expansions are substituted by the use of demand flexibility. This margin can accommodate benefits for both the DSO and the flexibility providers, in this paper, the households. When these benefits are within the limit set by the margin, then both sides can enjoy gains.

In the next sections the dimensions of the FlexMart model are defined, its structure as well as the flows of services and benefits among its market players. As discussed earlier, in (Ramos,

De Jonghe, Gomez, & Belmans, 2014), a flexibility market may be defined across four main dimensions, temporal, spatial, contractual and price-clearing. From the *temporal* point of view, the focus of the proposed market design
is the long term. The main motivation for this focus derives from the fact that investment decision on grid assets can only be made in the long-run. On the other hand, it may be tricky to use very long time frames such as a 10-year period, because the accuracy of load forecasting can be questioned. In this paper a 3-year planning period is considered for the simulations.

From an economic point of view, it might be a preferred strategy to study locally only a fragment of the market, i.e. price zone, since it can be assumed without damaging the generalization that all players included are price takers and no quantity or price games can be played from their part. This assumption can be justified by the fact that the smaller the segment of a price zone, the smaller the market power that may be concentrated over the greater price zone. A distortion due to market power exercise would hamper our ability to arrive to unbiased results. Hence, alongside the *spatial dimension*, a local approach has been adopted.

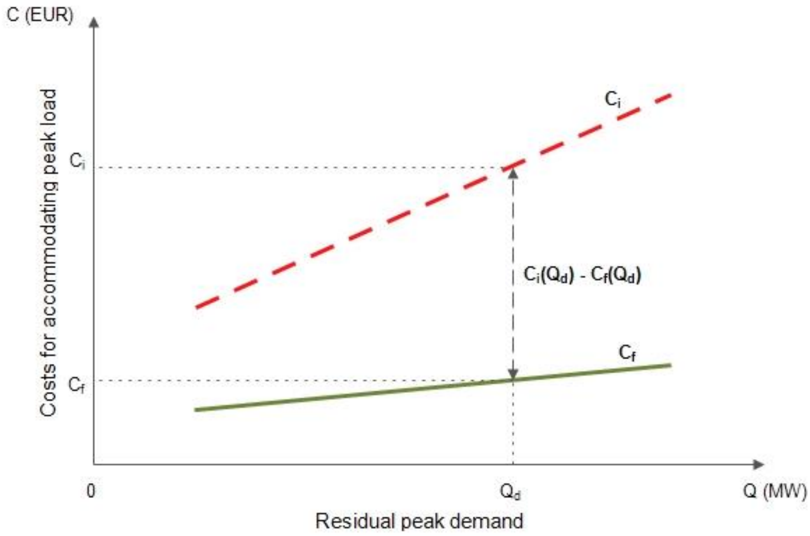


Fig. 2. Savings occurred by deferring investment in the physical network and using flexibility instead.

Considering the *contractual* aspect of the suggested market arrangement, the concept of aggregating unit (AU) is introduced. Residential users have a relatively low consumption and hence not enough to allow them participating in energy markets. Despite that, such an involvement would be rather time consuming for the consumers. An AU could allow them to participate in the market indirectly, by combining the capabilities of several consumers. This AU is assumed to be a non-profit intermediary for the purposes of this work. Profit masking by a commercial AU could have affected the estimation of an actual value and potential of flexibility which is investigated in this paper. To consider competing commercial AUs, an equilibrium model could be used to estimate the price of flexibility services offered to the DSOs; but this approach is not within the scope of the presented work. In this paper, the research is focused on the relationship between DSO costs and the cost for investing in flexibility from the part of the consumers.

Considering the *price clearing* dimension, a regulated approach has been adopted. This approach offers the consumer a fixed benefit and thus eliminates the risk associated with price volatility. This benefit allows consumers to recover their investment in flexibility-associated equipment, i.e. advanced metering devices and control unites, incremented by a predefined return on investment (ROI) rate. The actual compensation for the consumer, S_n (€), is calculated as the fixed benefit minus the savings due to price differences, as seen in **Eq.1**:

$$\mathrm{S_n} = \mathrm{INV_n} \cdot (1 + \mathrm{ROI}) - Price\ Benefit_n \qquad \textbf{Eq.1}$$

The scope, the participants and the flows of the FlexMart arrangement are illustrated in **Fig. 3**. Several residential consumers, i.e. households, are aggregated under the AU. For the purposes of clear illustration, only household n is depicted in **Fig. 3**. Household n offers its demand flexibility, Δd_n (kW) to the AU. When necessary, this demand flexibility is utilized to serve the needs of the network. The resulting demand shifting will induce a difference in the electricity consumption rent, ΔP (€). To reassure that the flexible demand providers will secure a benefit by participating to FlexMart, a guaranteed benefit is provided to them.

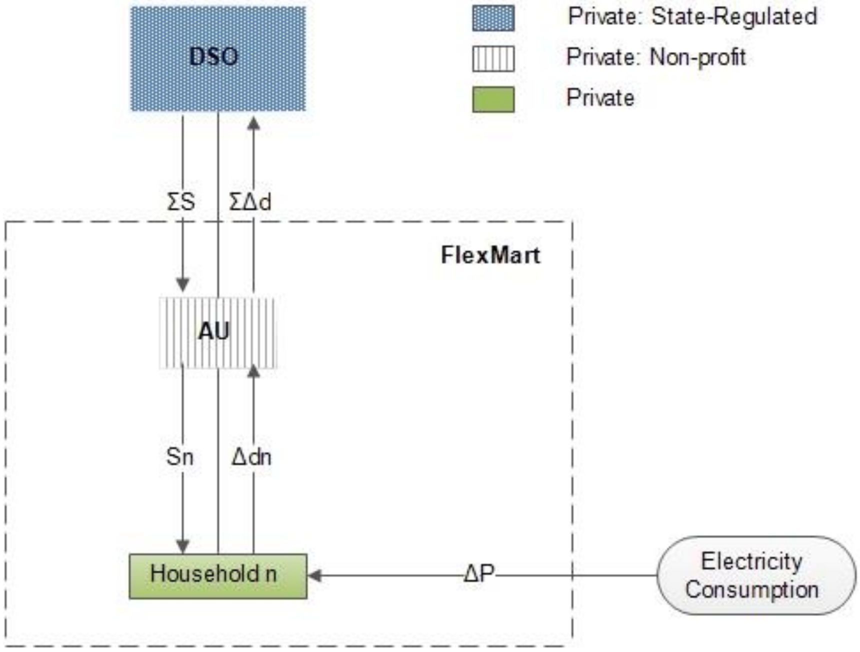


Fig. 3. Flows in the FlexMart mechanism.

3.2. Empirical model and mathematical framework

According to the context of constrained optimization, a problem is described by an objective function to be maximized or minimized subject to a set of constraints. The objective function is built step by step in a mathematical form. The constraints will also be discussed and their mathematical formulation will be given.

The formulation of the objective function is the DSO total cost function described by **Eq. 2** and its components by **Eq. 3**, **Eq.5** and **Eq.6**. Components of the cost such as variable costs, commercial costs, invoicing et cetera, are not considered since they are irrespective to the flexibility versus investment decision, as they can be assumed to be the same in both cases. Apart from the cost of the incremental expansion of the lines, additional components need to be added. First, the DSO's cost for contracting demand flexibility is comprised of the supplementary revenue to the consumers, S (€). Finally, solar installations have been considered in this network and hence the possibility of curtailing should be available to allow more controllability of the system output. Hence, the total cost that needs to be minimized can be expressed as set in **Eq. 2**.

$$\mathrm{TC} = c_{exp} + c_{flex} + c_{curt} \qquad \textbf{Eq. 2}$$

According to **Eq. 2**, the DSO's total cost consists of the expansion costs, c_{exp} (€), the flexibility costs, c_{flex} (€), and curtailment costs, c_{curt} (€). The curtailment costs have been added to the DSO's total costs, since it has the chance to curtail the distributed generation if necessary to limit congestions in its grid. The cost for expanding the line l is given by **Eq. 3** and it is equal to the the capacity to be incremented, k_{exp} (kW), times the expansion costs per unit, C_{line} (€), where L is the set of all the lines belonging to the given network configuration.

$$c_{exp} = \mathrm{C_{line}} \cdot \textstyle\sum_{\mathrm{l \in L}} k_{exp_{\mathrm{l}}} \qquad \textbf{Eq. 3}$$

Before presenting the cost of the DSO for flexibility, it is important to demonstrate what is the price benefit and how is it calculated. Price benefit is a saving that occurs for the consumers by shifting their demand from high priced peak hours to low priced off-peak hours. The savings of a given flexible demand providing consumer n, due to price differences between the hours of power consumption before and after the demand shifting, are calculated based on **Eq. 4**, where P_t is the price at hour t, Q_t^D is the power demand at hour t, $q_t^D{}_{down}$ and $q_t^D{}_{up}$ represent the optimal demand decrease and the demand increase respectively. To construct the following equations, the P_t, wholesale price, is considered for the transactions among the DSO and the flexibility providing consumers.

$$Price\ Benefit_n = \textstyle\sum_{\mathrm{t}} \left(\mathrm{P_t} \cdot \mathrm{Q_t^{D_n}} - \mathrm{P_t} \cdot \widehat{q_t^{D_n}}\right) = \sum_{\mathrm{t}} \left\{\mathrm{P_t} \cdot \mathrm{Q_t^{D_n}} - \mathrm{P_t} \cdot \left(\mathrm{Q_t^{D_n}} - q_t^{D_{down_n}} + q_t^{D_{up_n}}\right)\right\} = \sum_{\mathrm{t}}\{\mathrm{P_t} \cdot (q_t^{D_{down_n}} - q_t^{D_{up_n}})\} \qquad \textbf{Eq. 4}$$

Now, looking to the DSO, the cost to contract flexibility can be calculated according to **Eq. 5**. The DSO pays to the flexibility providing consumers their initial capital invested in flexibility-related equipment, i.e. advanced metering devices, incremented by the predefined ROI rate, minus the savings that the consumers already made by the demand shifting, namely, their price benefit. (see **Eq. 4**).

$$c_{flex^1} = \textstyle\sum_{\mathrm{n}} \sum_{\mathrm{t}}[\mathrm{INV_{flex_n}} \cdot (1 + \mathrm{ROI}) - \ Price\ Benefit_n \qquad \textbf{Eq. 5}$$

Finally, the curtailment cost is assumed to be remunerated based on the spot price, P_t, multiplied by the volume of the curtailed power, as it is observed in **Eq. 6**.

$$c_{curt} = \textstyle\sum_{\mathrm{n,t}} \mathrm{P_t} \cdot curt_{n,t} \qquad \textbf{Eq. 1}$$

Combining the above equations of the cost components, the objective function of the optimization problem is derived in **Eq. 7**.

$$\mathrm{TC} = \mathrm{C_{line}} \cdot \textstyle\sum_{\mathrm{l \in L}} k_{exp_l} + \sum_{\mathrm{n}} \sum_{\mathrm{t}}[\mathrm{INV_{flex_n}} \cdot (1 + \mathrm{ROI}) - \left\{\mathrm{P_t} \cdot \left(q_t^{D_{down_n}} - q_t^{D_{up_n}}\right)\right\} + \sum_{\mathrm{n,t}} \mathrm{P_t} \cdot curt_{n,t} \qquad \textbf{Eq. 2}$$

In **Table 1**, the cash flows described above are listed. The source, beneficiary and the corresponding unit price are listed alongside the cash flows.

Table 1
Cash flows, their source and beneficiaries and the price to determine them.

Cash Flow	Source	Beneficiary	Price per unit
$\mathbf{C_{flex}}$	DSO	Consumer	INV*(1+ROI)-Price Benefit
Price Benefit$_n$	Savings on market prices (ΔP)	Consumer	P_t
$\mathbf{C_{curt}}$	DSO	Consumer	P_t

[1] C_{flex} is the cash flow from the viewpoint of the DSO. The same amount is referred to as S_n (supplementary payment) from the viewpoint of the consumers, since it is the amount they receive on top of their price benefit savings.

C_{exp}	DSO	In-house/outsource construction cost	C_{line}

The objective function is minimized subject to several constraints. The power balance constraint requires that the supplied power matches the amount of consumed power at all times and it is described by **Eq. 8**. In this study, the supply consists of the power imported to the feeder from the grid, the PV generation and its curtailment, and of the original demand adjusted by the up and down regulation.

$$p_{imp_t} + \sum_{\mathrm{n}}(\mathrm{PV_{n,t}} - curt_{n,t}) = \sum_{\mathrm{n}}(\mathrm{Q_t^{D_n}} - q_t^{D_{down_n}} + q_t^{D_{up_n}}),\ \forall \mathrm{t} \qquad \textbf{Eq. 3}$$

Concerning the imported power, p_{imp}, and the capacity expansion, k_{exp}, upper and lower limits are used to ensure that the variables are bounded. Eq. 9 and Eq. 10 contain the respective constraints that are added.

$$\underline{\mathrm{P_{imp}}} \leq p_{imp_t} \leq \overline{\mathrm{P_{imp}}},\ \forall \mathrm{t} \qquad \textbf{Eq. 4}$$

$$\underline{\mathrm{K_{exp}}} \leq k_{exp_l} \leq \overline{\mathrm{K_{exp}}},\ \forall \mathrm{l} \in \mathrm{L} \qquad \textbf{Eq. 5}$$

The optimization variable k_{expl} represents the incremental expansion of line l. The line flow $f_{l,t}$ is a function of the power injected into the network at that time, and is determined by solving the lossless DC power flow within the examined feeder. The power flow on each line l of the feeder is bounded according to **Eq. 11**, where CAP_l represents the initial capacity of line l.

$$f_{l,t} \leq \left|\mathrm{CAP_l} + k_{exp_l}\right|,\ \forall \mathrm{l} \in \mathrm{L}, \forall \mathrm{t} \qquad \textbf{Eq. 6}$$

Finally a set of constraints are also needed to model flexibility. First, for the purposes of this study, it has been assumed that flexibility is modelled as a percentage of the total consumption. This percentage is contained in the parameter $COEF_{flex}$. **Eq. 12** and **Eq. 13** ensures that up- and down-regulations of the demand do not violate the flexibility coefficient. Second, a constraint is added to ensure that the demand is simply shifted and not curbed. For example, if at a time instance t_1 the power consumption has to be decreased by 100 W, this has to be consumed later at an optimal time t_2 within a predefined time frame that respects the comfort of the user. This time frame is configured by adjusting the t_s, which is a subset of the time horizon. This functionality is ensure through introducing equation **Eq. 14** to the constraints.

$$q_t^{D_{down_n}} \leq \mathrm{COEF_{flex}} \cdot \mathrm{Q_t^{D_n}},\ \forall \mathrm{n,t} \qquad \textbf{Eq. 7}$$

$$q_t^{D_{up_n}} \leq \mathrm{COEF_{flex}} \cdot \mathrm{Q_t^{D_n}},\ \forall \mathrm{n,t} \qquad \textbf{Eq. 8}$$

$$\sum_{\mathrm{t_s}} \left\{q_t^{D_{down_n}} - q_t^{D_{up_n}}\right\} = 0 \qquad \textbf{Eq. 9}$$

4. Input data

Firstly, the composition of the studied system is discussed. Two distribution networks are considered, feeder I and feeder II. **Fig. 4** shows feeder I, a 12-node straight-line radial distribution feeder. **Fig. 5** shows feeder II, a 24-node radial network with branches. In these figures, the white triangles represent the connected households and the sun symbolizes the presence of a roof PV installation. Both of the feeders are assumed to be lossless circuits with identical impedance between the different nodes. The choice of input parameters of this system are discussed and motivated in the remainder of this subsection.

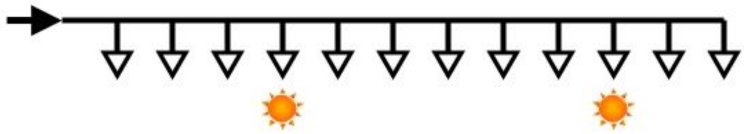


Fig. 4. 12-node straight radial distribution network (feeder I)

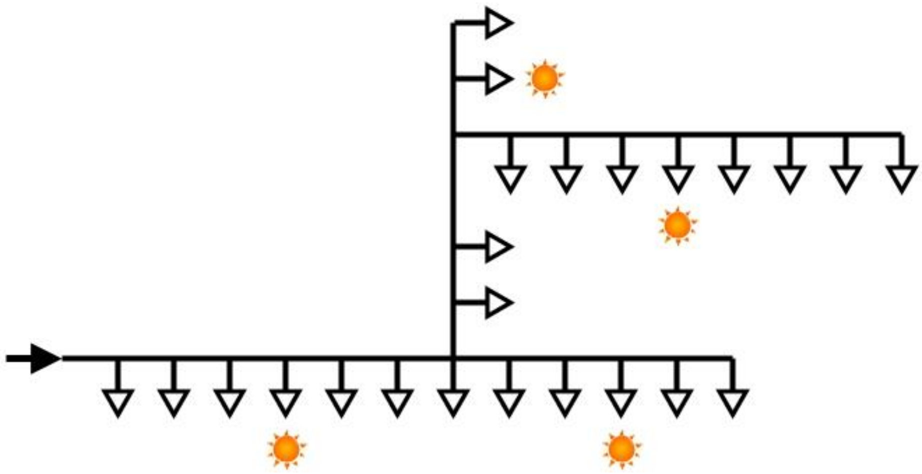


Fig. 5. 24-node radial distribution network with branches (feeder II)

Several sources were consulted to obtain data on the characteristics of the power consumption, PV profiles and prices. First, the data on the power consumption of the households have been retrieved from the website of Synergrid (Synergrid, 2015). The synthetic load profiles published by Synergrid, are the average consumptions of the Belgian households. Please refer to **Fig. A.1** of annex I. Second, the PV profiles have been retrieved, using a toolbox developed by NREL (NREL, 2015) and they are illustrated in **Fig. A.2** in annex I. Finally, the price sequence has been retrieved from the BELPEX platform (BELPEX, 2015). To view the pricing profile, please refer to **Fig. A.3** of annex I. As it has been outlined also in the previous section, the wholesale price, P_t, has been considered and dynamic pricing has been assumed. Currently, most consumers purchase fixed-price energy contracts and hence price volatility is not reflected in their energy bills (Dupont, De Jonghe, Olmos, & Belmans, 2014). In such a case it would not be possible to estimate the savings incurred by price differences. A weekly price profile has been used for the purposes of the empirical test of the proposed model.

In this study, the demand flexibility is modeled as a percentage of the total demand at each of the time intervals. Considering different works that have been carried out in the level of appliances (Woon, Aung, & Madnick, 2014), (Tahersima, Madsen, & Andersen, 2013), the flexible demand can represent a percentage varying largely from 2% up to more than 20%. An average demand flexibility coefficient of 10% is considered here. However, in the sensitivity analysis a wide range of demand flexibility coefficient is considered to cover different scenarios.

During the calibration of the model, capacities were assigned to the lines in such a way that congestion occurs and hence a comparative study, flexibility versus physical expansion, could be performed. As it is evident also in **Fig. A.4** in annex I the initial capacity of all lines of both feeders I and II is set at 8 kW. An average cost of the physical network expansion of €6000/kW has been considered. This indicative cost is an estimate, considering average costs and distances of distribution networks that have been found in the literature (Hau, 2013), (Shirley, 2001). Since in practice the actual cost may defer significantly, a sensitivity analysis is carried out considering different values of this parameter.

Concerning the value of the ROI, the rate of 10% has been selected. Based on historical data, (CSI Market, 2015), a ROI of 10.83% has been achieved in the energy sector. The current ROI is settled at the rate of 5.58%, but since it is subject to fluctuations, the use of the historical average has been preferred to avoid high specificity. The developed model offers the possibility to modify the ROI to adhere to the specifics of an applicable region or period.

5. Results and discussion

This section provides a summary of the results of the empirical testing. The input data presented in the previous section, have been used to demonstrate how the developed optimization model works. A sensitivity analysis on the input parameters is also included for the purpose of verifying how the results can defer given different circumstances. The results are presented alongside comments and clarifications when necessary. The final section of this chapter contains a summary of the results, as well as, discussion and conclusion on them.

In **Fig. 6**, the distribution of the costs for the DSO is presented corresponding to feeders I and II respectively. The case where demand flexibility is used is printed in the upper subplots. At the end of the planning period, it can be seen that the total cost of the DSO is reduced when demand flexibility is utilized. It can be seen that the price benefit incurred by demand shifting for the consumers is rather small in both feeders and that is a reason that the supplementary payment is quite high. When, no flexibility is used, the total cost is entirely composed by the expenses for physical expansions. Curtailment of the PV output occurs in feeder II only for the case when no demand flexibility is used. In the same feeder, the supplementary payment (flexibility cost) payable by the DSO to the consumers, constitutes only the 3.6% of the total costs of the DSO, which makes the use of flexibility particularly effective in cost minimization as capital expenses are reduced by almost 22%.

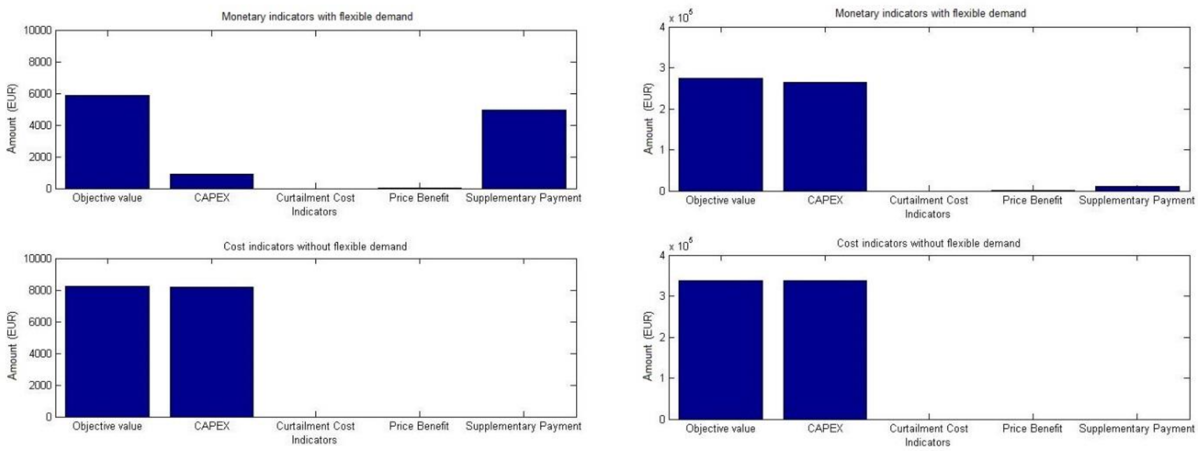


Fig. 6. Comparison of the monetary indicators for feeder I (left) and feeder II (right), with the use of demand flexibility (up) and only with physical expansions (down). The price benefit saved by the consumers is also listed as it is partially determining the supplementary payment (flexibility cost) that is payable by the DSO to the consumers.

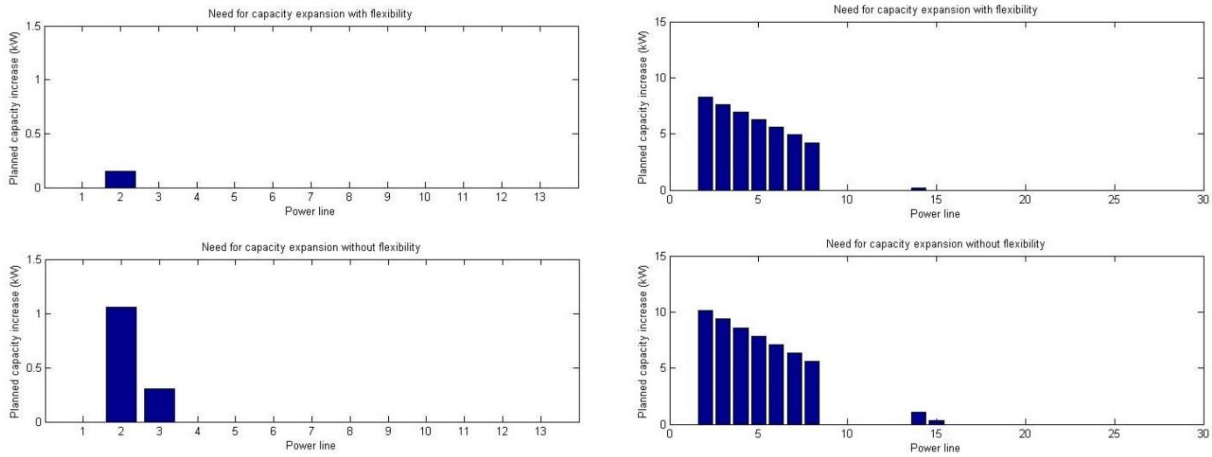


Fig. 7. Planned distribution line capacity expansions for feeder I (left) and feeder II (right), with the use of demand flexibility (up) and only with physical expansions (down).

The DSO cost reduction is due to the reduction of the cost for physical expansions, mentioned as capex. This can be evident in **Fig. 7**. In the same figure, it can be noticed that indeed the use of demand flexibility can reduce the need for physical expansions in the distribution grids. For the case of feeder I, the reduction in capacity incremental reinforcement in all lines is reduced by almost 90%, and for feeder II, the reduction reaches up to 22%. Another observation is that the nodes connected closer to the feeding point in a radial network are more vulnerable to notice congestion in their links between them. Hence, it might be beneficial to incentivize such nodes to increase their flexibility potential further.

In **Table 2**, a summary of the different monetary and capacity indicators for feeder I and II is given. Monetary indicators include the expenses for physical grid investments, namely CAPEX, the cost for curtailing part of the PV output, the price benefit and the additional supplement for the customers, and the benefit for the DSO. The capacity indicators include the volume of the required physical expansions, the curtailment and the dispatched demand flexibility. Based on both cost and capacity indicators a flexibility price per kWh is calculated and given.

Table 2
Summary of monetary and capacity indicators for feeders I and II, given in percentages by comparing the cases of using demand flexibility and of relying entirely on physical expansions.

Monetary Indicators	**Feeders**	
	Feeder I	**Feeder II**
% reduction of CAPEX with the use of flexibility	-88.74%	-21.85%
% price benefit on consumer earnings	0.8%	0.75%
% flexibility contracting cost on total DSO cost	84.38%	3.63%
% DSO total cost reduction with the use of flexibility	27.91%	18.89%
Capacity indicators		
% reduction of line expansions with the use of flexibility	-88.81%	-21.43%

% reduction of curtailment with the use of flexibility	-	-100%[2]
Flexibility price		
Price	10.64 €/kWh	10.75 €/kWh

The positive effect of the flexibility is the reduction in the cost of physical expansions. That effect is noted in both feeders I and II, as observed on **Table 2**. The price paid by the DSO to the prosumers for this positive effect of flexibility equals the supplement, the cost of guaranteeing the prosumers a fixed benefit. In both cases, the cost has been estimated in the vicinity of 10 €/kWh. The savings in expansion cost are larger than the supplement and result therefore in overall cost reduction for the DSO.

Moreover, in feeder II, flexibility worked very positively on preventing any curtailments on the PV output. As it has been stated in the hypothesis of this paper, demand flexibility can facilitate the increasing penetration of RES in the grid; the scenario of feeder II demonstrates this capability.

Finally, a sensitivity analysis was carried out on the main input parameters. These parameters include the percentage of the electricity consumption regarded flexible, namely the flexibility coefficient, the costs for line capacity expansions, the power consumption, the electricity price, the output of the PV installations and the ROI rate. For each of the input parameters variations from -50% to +50%, in other words from 50% to 150%, with a step of 5%, of the initial values described in section 4 are inserted to the model, considering feeder I. **Table 3** presents the ranges of the values of the parameters that have been considered in the sensitivity analysis. The comparative figures produced by the sensitivity analysis are plotted across these variations, referred to as sensitivity coefficient of the concerned parameter. To avoid having an overwhelming number of figures in this section, the figures about flexibility coefficient, capacity expansion cost per unit and ROI are plotted here and the rest are included in annex I. In each figure, the expansions costs with and without flexibility as well as the cost to contract flexibility are presented. That allows to examine how a variation of the parameters affect the magnitude of the benefits that flexibility can offer to a DSO with respect to investment cost minimization.

Table 3
Ranges of values of the parameters on which sensitivity analysis was performed. For power consumption, price and PV output the peak values are given as an indication, as these parameters contain sequence of data and not scalar values as the rest.

Parameter	**Sensitivity coefficient** 50% (minimum)	100% (initial input)	150% (maximum)
Flexibility coefficient	5%	10%	15%
Capacity expansion cost per unit	3000 €/kW	6000 €/kW	9000 €/kW
Power consumption (peak)	0.375 kW	0.75 kW	1.125 kW
Price (peak)	0.14 €/kWh	0.28 €/kWh	0.42 €/kWh
PV output (peak)	0.85 kW	1.7 kW	2.55 kW
ROI	5%	10%	15%

[2] Please refer to **Fig. A.5** in annex I to observe the comparison of the performance of the capacity indicators, namely, the necessary line expansion, the curtailment and the amount of the mobilized demand flexibility.

As observed on **Fig. 8**, in the scenario where the flexible demand comprise the 12% of the total consumption (at 120% of the sensitivity coefficient), all physical expansions would have been avoided, bringing the respective cost to 0, maximizing the cost savings for the DSO, to over €3000 in total. On the contrary, for flexibility shares of 6% of the total consumption or lower, the contracting of flexibility would be more costly than simply expanding the lines. The cost for contracting flexibility remains stable at €4978.70, since it is based on the ROI rate and cost for installing flexibility – associated equipment.

Fig. 9 illustrates how the cost savings for DSO thicken as expansion costs grow more than the nominal value. On the contrary, savings deteriorate as physical grid expansions become cheaper. At an expansion cost of €3600 per kW, only the costs for contracting flexibility alone exceed the costs for physical expansion. When no flexibility is considered, the required physical expansions are more intensive, hence the respective cost (blue) tends to increase at a rather higher rate, compared to the case where flexibility is used. For the cases where increased line expansion costs are expected, contracting flexibility at the predefined fixed rate might be a good solution to keep DSO expenses lower.

Fig. 10 depicts the impact of variations of the ROI rate on the DSO cost reductions. Since the flexibility costs are associated to the installation costs and the ROI rate, obviously, a higher ROI rate can will result in larger costs for contracting flexibility. Hence, the cost savings for the DSO will be less when compared to scenarios of lower ROI rates. Even at a ROI rate of 15% (150% of the initial value), still it would be beneficial to contract flexibility instead of only expanding the lines.

Variations of the power consumption affect the expansion and flexibility costs in a trivial manner, whilst variations of the wholesale prices and the PV output have no effect on the resulting costs. Please refer to **Fig. A.6**, **Fig. A.7** and **Fig. A.8** in annex I to observe the respective figures.

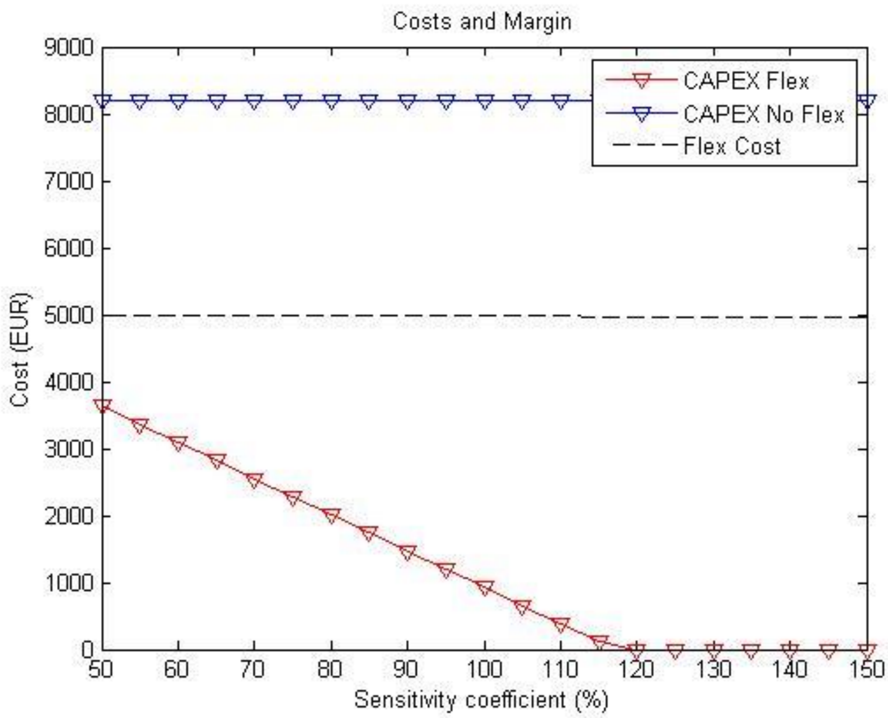


Fig. 8. Sensitivity on the % of flexible demand – Total expansion cost without demand flexibility (blue), with demand flexibility (red) and for contracting flexibility (black).

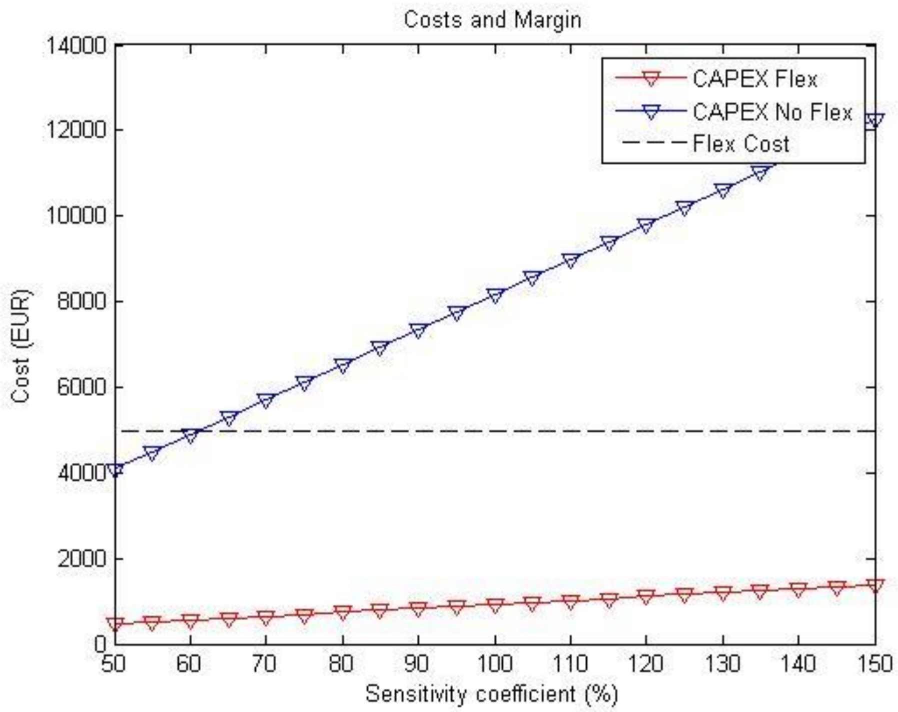


Fig. 9. Sensitivity on line capacity expansion cost – Total expansion cost without demand flexibility (blue), with demand flexibility (red) and for contracting flexibility (black).

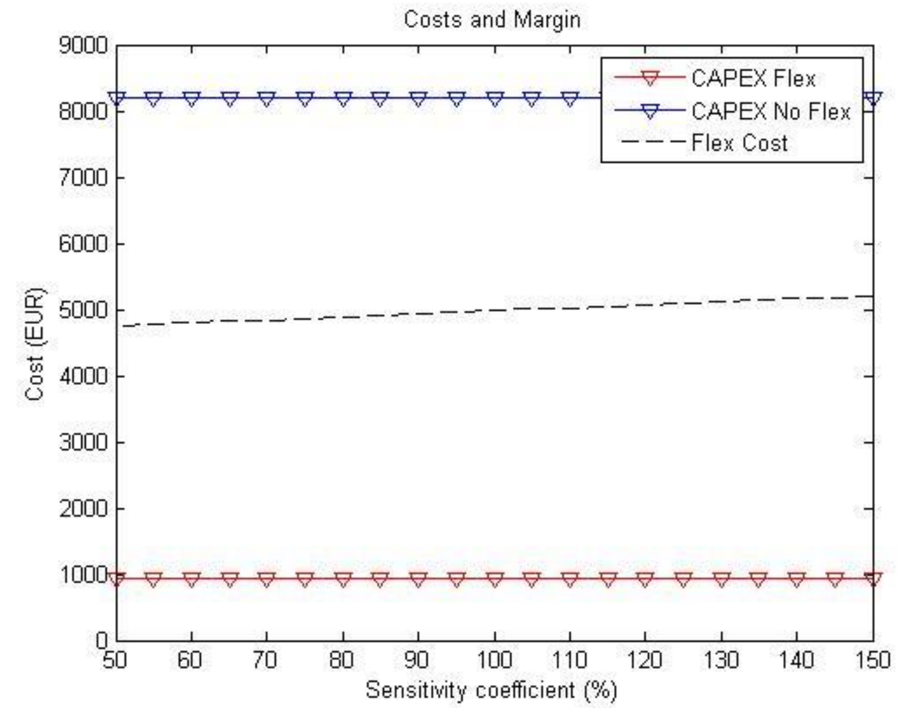


Fig. 10. Sensitivity on ROI rate – Total expansion cost without demand flexibility (blue), with demand flexibility (red) and for contracting flexibility (black).

As summarized on **Table 4**:

- More demand flexibility, i.e. higher flexibility coefficient, is better. DSO savings are seeing an increase as the percentage of flexible demand is growing, whilst expansions are kept low.

- The costs for physical expansions have a negative impact on the DSO savings, as expected.
- Variations of the ROI rate affect positively consumers' benefits and negatively the DSO savings.

Table 4
Sensitivity analysis – impact of the parameters on DSO savings, consumer benefit and line capacity expansions.

Parameter		DSO savings	Consumer benefit	Capacity Expansions
Flexibility coefficient	Hi	++		++
	Low	--		--
Capacity expansion cost per unit	Hi	--		
	Low	++		
Power consumption	Hi	+		--
	Low	-		++
Price	Hi			
	Low			
PV output	Hi			
	Low			
ROI	Hi	-	+	
	Low	+	-	

6. Conclusions and policy implications

Flexibility is a necessary helps deal with congestion issues in a power system. The increasing trends of small-scale distributed generation, intermittent RES and EVs among others, dictate this necessity even more. Due to increasing intermittency and uncontrollability, generation-side flexibility becomes scarce. This paper highlights and examines the possible contribution of demand-side flexibility in distribution grids congestion management. To tackle the topic, both a conceptual and an empirical framework have been developed, namely FlexMart. The modeling framework investigates whether the use of demand flexibility can defer or limit the physical expansions of the lines of local distribution grids.

As illustrated in the previous section, depending on the grid parameters, it is possible that contracting demand flexibility might limit the need for physical expansions of the lines. Such an investment deferral can allow the DSO to reduce costs and consumers to reduce their energy bills. Hence, a regulatory framework that allows DSO to contract the domestic demand flexibility might be beneficial for both parties, DSO and consumers. Furthermore, it might be beneficial to give DSOs the incentive to avoid capital-intensive expansions and turn to innovative methods for congestion management, such as the use of demand flexibility.

The proposed way to bridge the DSO and the consumers is through the AUs. The direct cooperation between the two parties would not be realistic. Transaction costs, required time and personnel to facilitate the process, indicate the need for an intermediary entity which can aggregate the flexibility capabilities of several consumers and offer them to the DSO. Due to a limited number of market actors and liquidity in local markets, AUs are considered as non-profit entities in this work. Within a realistic regulatory framework, AUs could be formed and managed by a consortium of concerned stakeholders, including local authorities, utilities and consumers.

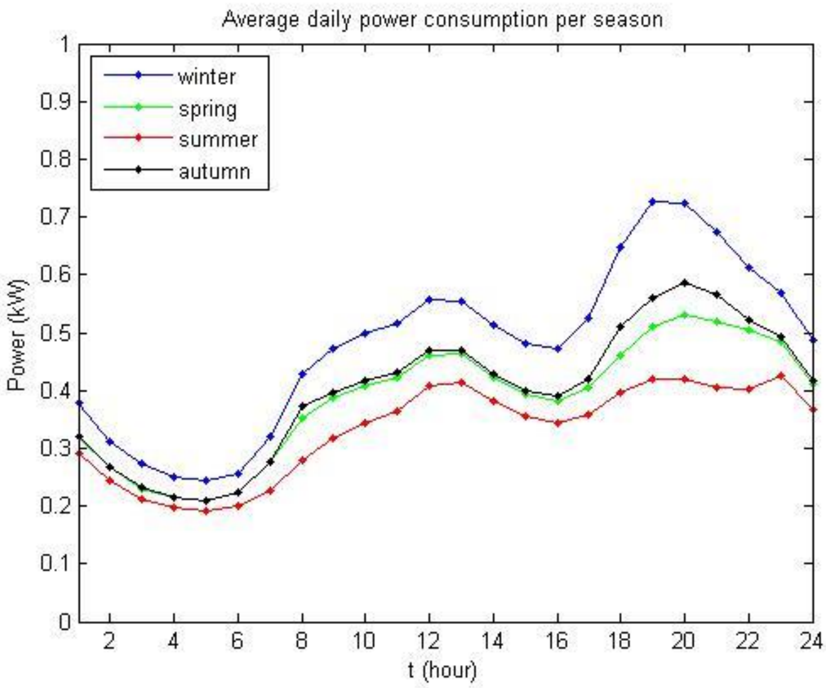
This paper suggests also a fixed and risk-free flexibility remuneration mechanism. A shift of the consumers' demand from an hour to another might induce a price benefit. It is proposed that a fair benefit for the consumers should be to recover their investment costs in flexibility-related equipment incremented by the ROI rate. The DSO, in other words the beneficiary of the flexibility, is responsible to cover the difference between the incremented investment costs of the consumers and their price benefit. Such a mechanism can empower consumers to participate in flexibility schemes by limiting their risk to a minimum. A shift to dynamic energy pricing on the retail level would serve this purpose. Fixed price-volume retail energy contracts and this remuneration mechanism would be incompatible.

The model developed in this paper has the ability to calculate the optimal combination of physical grid expansions, demand flexibility dispatch and curtailment of the PV installations output. As the previous section demonstrated, for a given network configuration and parameters, the empirical model returns the required expansion, the schedule of dispatched flexibility and curtailment throughout the planning period. Additionally, the model provides an indicative price per unit of flexibility and quantifies the benefits for the DSO and the consumers concerned. The model can be used by utilities, regional and city planners and policy makers, as a decision support and screening tool.

Acknowledgement

I would like to cordially thank my dear friend and colleague, Sander Claeys for his valuable feedback, insights and continuous support.

Annex I



- **Fig. A.1**. The average Belgian daily household consumption per season (source Synegrid).

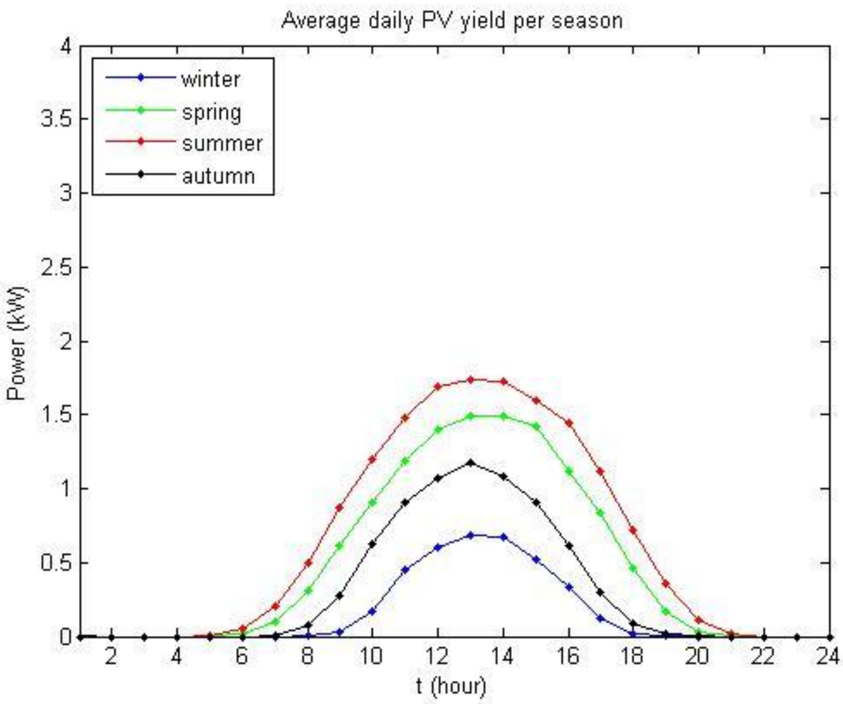


Fig. A.2. The power output of an average Belgian roof PV of 4kW installation per season (source: PVWatts).

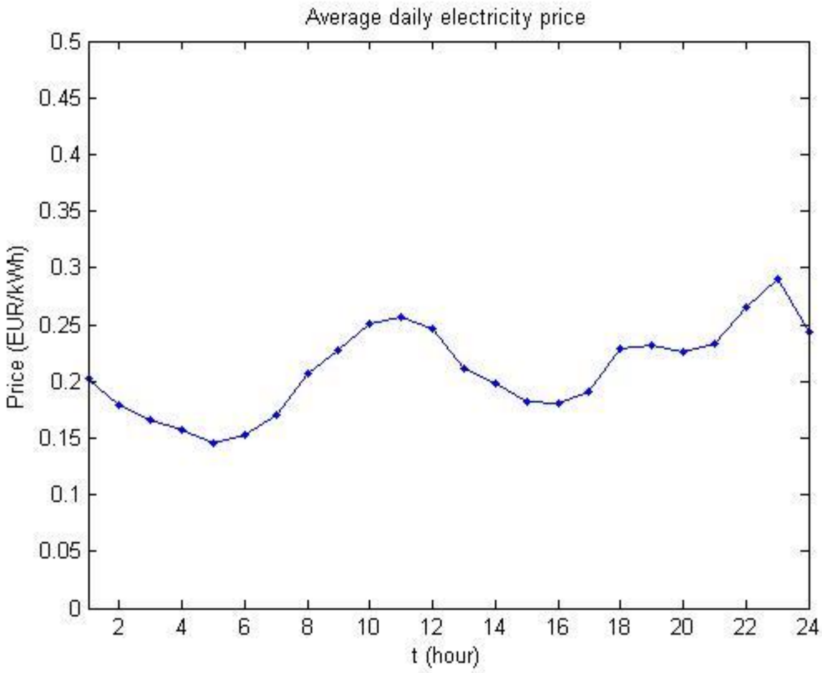


Fig. A.3. Average daily electricity price (source: BELPEX).

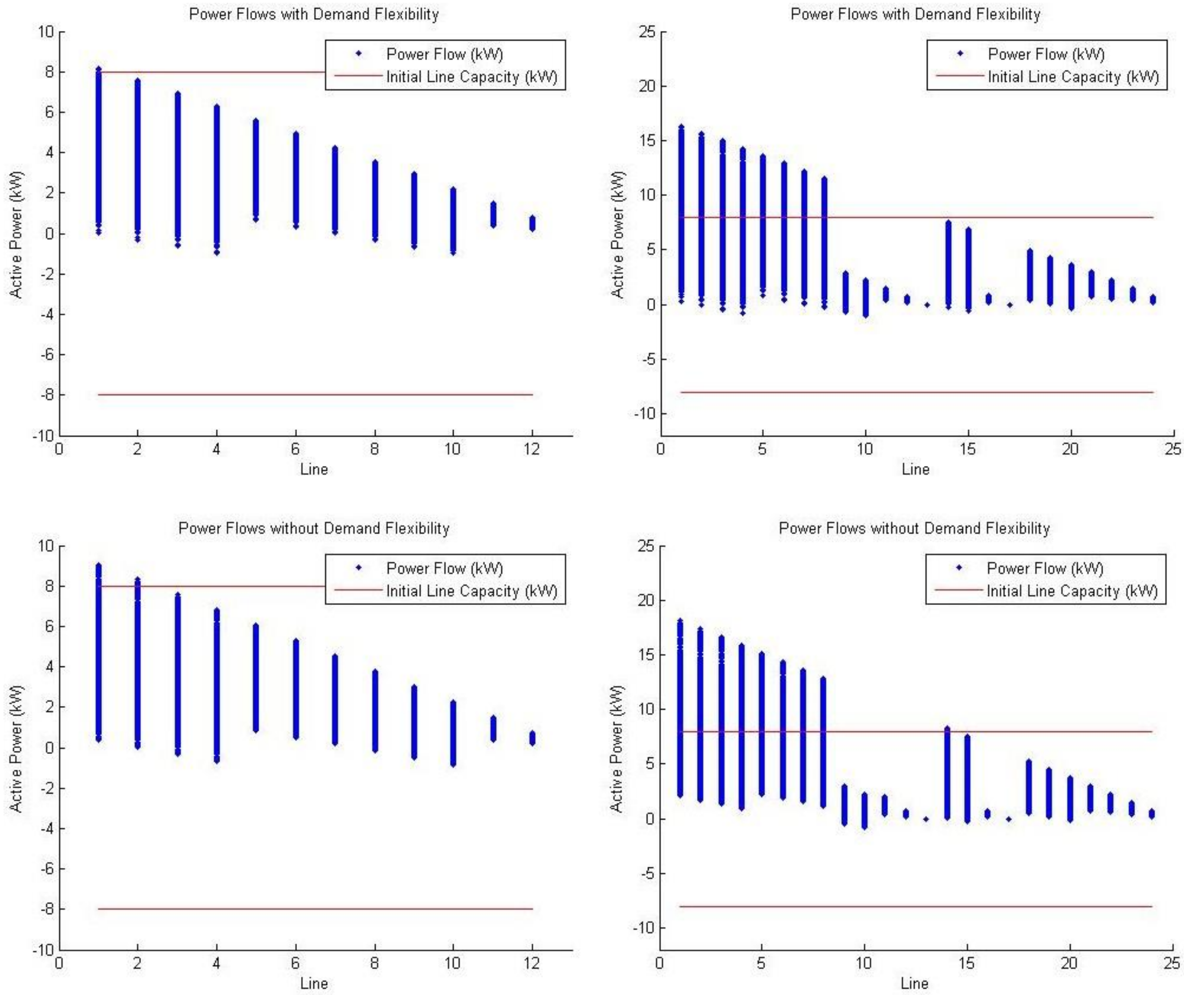


Fig. A.4. Instances of the power flow over the lines (blue dots) and the initial line capacities before any expansions (red) for feeder I (left) and feeder II (right), with the use of demand flexibility (up) and only with physical expansions (down).

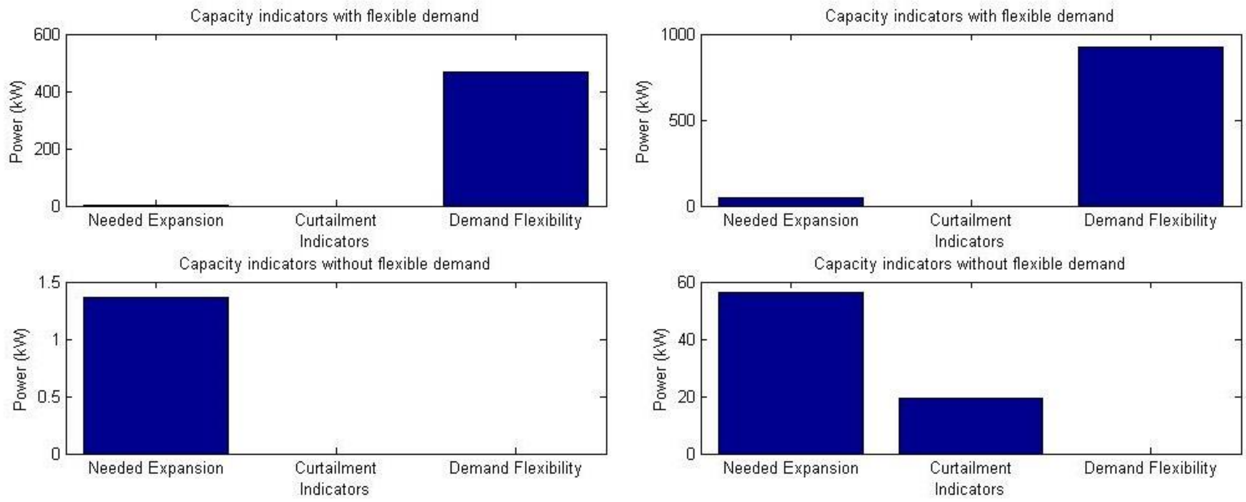


Fig. A.5. Comparison of the capacity indicators for feeder I (left) and feeder II (right), with the use of demand flexibility (up) and only with physical expansions (down).

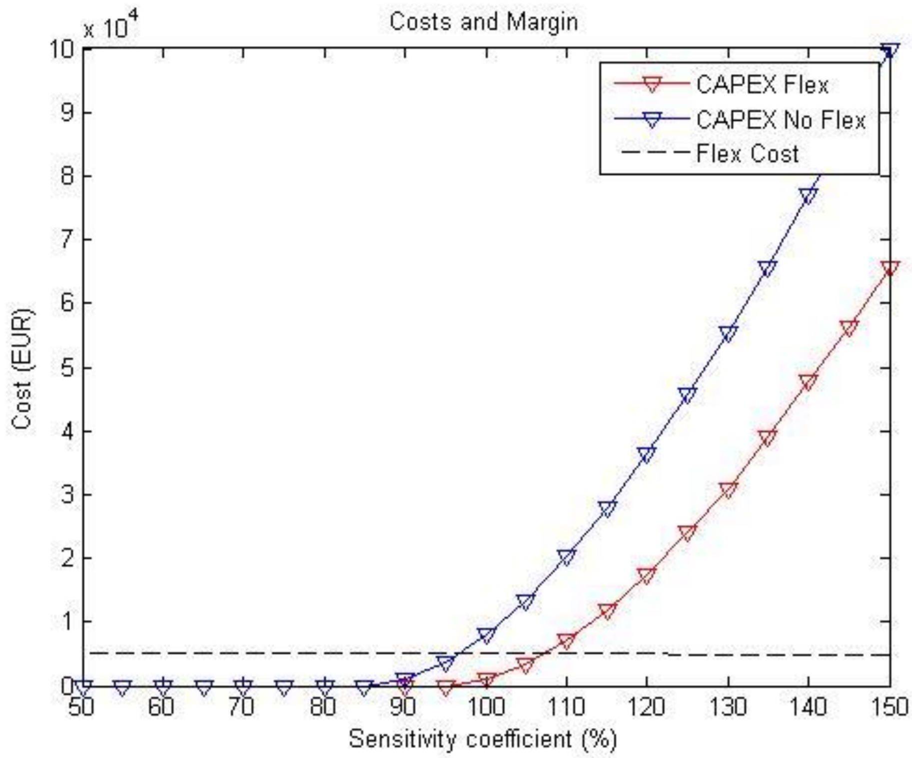


Fig. A.6. Sensitivity on power consumption – Expansion cost without demand flexibility (blue), with demand flexibility (red) and cost for contracting flexibility (black).

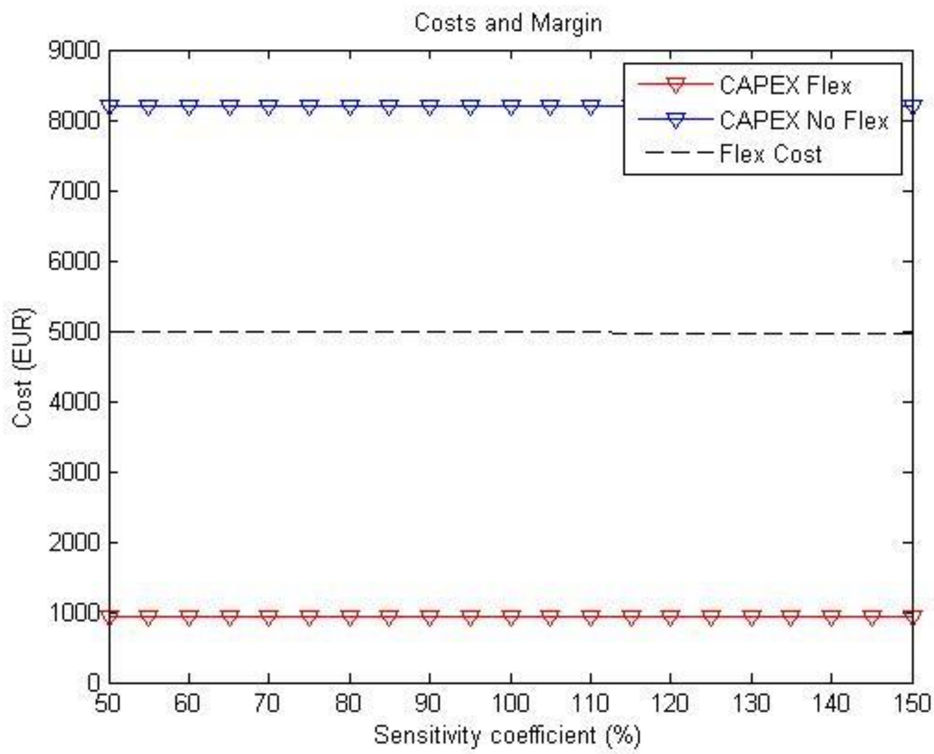


Fig. A.7. Sensitivity on electricity price – Expansion cost without demand flexibility (blue), with demand flexibility (red) and cost for contracting flexibility (black).

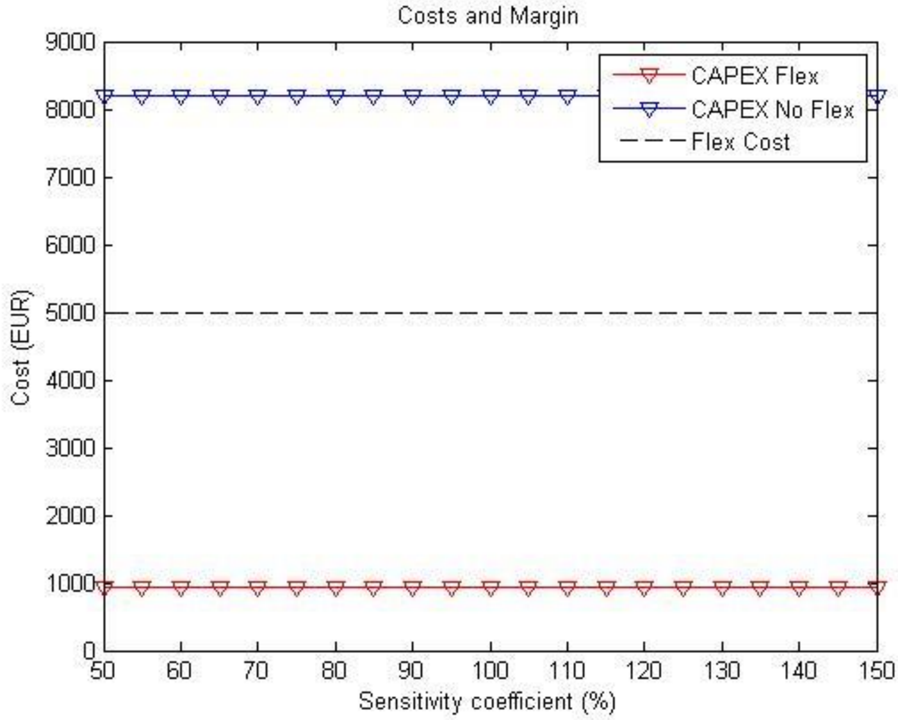


Fig. A.8. Sensitivity on PV Output – Expansion cost without demand flexibility (blue), with demand flexibility (red) and cost for contracting flexibility (black).

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